

STATE OF ILLINOIS

ILLINOIS COMMERCE COMMISSION

CENTRAL ILLINOIS PUBLIC SERVICE)
COMPANY and UNION ELECTRIC)
COMPANY)
)
Petition for approval of tariff sheets implementing) Docket No. 02-0656
revised Market Value Index methodology.)
)
COMMONWEALTH EDISON COMPANY)
)
Proposed revision of Rider PPO (Power Purchase) Docket No. 02-0671
Option - Market Index), Rate CTC (Customer)
Transition Charge) and Rider ISS (Interim Supply)
Services), and to establish Rider CTC - MY)
(Customer Transition Charge - Multi-Year)
Experimental). (Tariffs filed on October 1, 2002))
)
ILLINOIS POWER COMPANY)
) Docket No. 02-0672
) (Cons.)
Proposed establishment of Rider MVI II, Market)
Value Index II. (Tariff filed October 1, 2002))
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DIRECT TESTIMONY
OF
DR. DALE E. SWAN

ON BEHALF OF

THE
UNITED STATES DEPARTMENT OF ENERGY

EXETER

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DECEMBER 16, 2002

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DIRECT TESTIMONY
OF
DR. DALE E. SWAN

I. INTRODUCTION AND SUMMARY

- 1 Q. PLEASE STATE YOUR NAME, OCCUPATION AND ADDRESS.
- 2 A. My name is Dale E. Swan. I am a senior economist and principal with Exeter Associates, Inc.
- 3 Our offices are located at 12510 Prosperity Drive, Silver Spring, Maryland 20904.
- 4 Q. DR. SWAN, PLEASE SUMMARIZE YOUR PROFESSIONAL QUALIFICATIONS.

5 A. I hold a B.S. degree in Business Administration from Ithaca College. I attended a master's
6 program in economics at Tufts University, and I hold a Ph.D. in economics from the University
7 of North Carolina at Chapel Hill. Prior to my consulting work, I served as Assistant and
8 Associate Professor on the economics faculties of several colleges and universities. I also
9 served as staff economist with the Federal Energy Administration and with the Arabian
10 American Oil Company. For the last 25 years, I have consulted on matters primarily related to
11 the electric utility industry, the last 21 years with Exeter. Much of my work over the last two
12 decades has concentrated in the areas of long-term electric power supply planning and contract
13 negotiations for large power users, and on electric utility cost allocation and rate design. For
14 much of this period, I have directed Exeter's utility support services projects with the United
15 States Department of Energy (DOE). As part of this work, I have been responsible for
16 technical supervision of Exeter's participation in DOE interventions in numerous rate cases, for
17 the financial and locational assessment of transmission and generation projects, and for the
18 negotiation of technical aspects of power supply and facilities contracts. In the last several
19 years, my activities have also focused on the process of electric industry restructuring.

20 A complete copy of my resume is provided as an attachment to my testimony.

21 Q. HAVE YOU TESTIFIED IN OTHER REGULATORY PROCEEDINGS?

22 A. Yes. I have testified on a variety of topics relating to electric utilities in numerous proceedings
23 before federal and state regulatory commissions. A complete list of the cases in which I have
24 testified is provided as part of my resume.

25 Q. DR. SWAN, WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS
26 PROCEEDING?

27 A I have been asked by the U.S. Department of Energy (DOE), on behalf of the Federal
28 Executive Agency (FEA) customers of Commonwealth Edison Company (ComEd or the
29 Company), to provide comments on the appropriateness of several of the changes that ComEd
30 has proposed for its Market Value Index (MVI) methodology, its Purchased Power Option–

31 Market Index (PPO) process, and its experimental Rider CTC-MY– Customer Transition
32 Charges– Multi-Year(Experimental). Of particular concern is how these changes will apply to
33 FEA customers in their attempts to secure reliable supplies of electric power while managing
34 the price risks that are associated with obtaining those supplies in the market.

35 Q. WHAT SPECIFIC FEA CUSTOMERS DO YOU CONSIDER IN YOUR
36 COMMENTS?

37 A. My focus is on the largest of these FEA customers, with loads of 3 mW or more, and who
38 qualify for service under the bundled Rate Schedule 6L (Large General Service), as qualified by
39 the Order issued by the Illinois Commerce Commission (ICC) in Docket No. 02-0479, in
40 which it decided to allow the Company’s proposal to have Rate 6L for this group of customers
41 become a “competitive service” by operation of law. Specifically, the FEA customers in this
42 group include the DOE national laboratories, Fermi National Accelerator Laboratory and
43 Argonne National Laboratory; the U.S. Navy’s Great Lakes Training Center; and several large
44 buildings, the power for which is obtained by the U.S. General Services Administration (GSA).

45 Q. PLEASE PROVIDE AN OVERVIEW OF YOUR TESTIMONY.

46 A I believe the general direction of the Company’s proposed changes is beneficial to customers
47 who need to compare supply alternatives. In particular, the Company’s efforts to improve the
48 accuracy of its MVI calculations, and its proposal to advance the availability of MVI, PPO and
49 CTC information by two months and increase to approximately two months the time available
50 for a customer to decide whether to take PPO service are both marked improvements in the
51 process.

52 I also believe the Company’s proposal to offer Rider CTC-MY is a step in right direction
53 toward assisting customers in managing the risks associated with purchasing power from an
54 Alternative Retail Electric Supplier (ARES). However, as I shall explain shortly, the
55 Company’s effort on this score falls short of what is required, given the Commission’s Order in
56 Docket No. 02-0479, and I recommend that the Company’s Rider CTC-MY be extended to

57 provide a stable CTC through the period ending with the meter reading date in May 2006. This
58 would essentially extend the fixed CTC for an additional year compared to the Company's
59 proposal.

60 Finally, I raise some administrative concerns regarding the Company's proposal to limit the
61 availability of CTC-MY to 500 mW of load on a "first-come-first-served" basis.

62 Q. PLEASE EXPLAIN WHICH OF THE COMPANY'S PROPOSED CHANGES YOU
63 SUPPORT AND WHY.

64 A. The Company proposes several "technical changes" intended to improve the accuracy of the
65 MVEC estimates. These strike me as clear improvements, especially the use of off-peak
66 forward market prices rather than historical spot prices, and the use of several years of data to
67 create its price-shaping and load-weighting adjustments.

68 The Company also proposes certain structural changes in Rider PPO and Rate CTC that I
69 support. Specifically, the Company proposes to advance the Period A 20-day snapshot period
70 two months to the period ending January 24. It would then release the Period A Market Value
71 Energy Charges (MVECs) and CTCs on or about February 1, instead of the current April 1.
72 Customers would then have until March 31 to determine whether to select PPO service. This
73 provides approximately an extra month after receiving Period A information for the customer to
74 make its decision.

75 I have discussed these timing changes with representatives from the Defense Energy Supply
76 Center (DESC), which has the responsibility for competitively procuring electric power for
77 several of these large FEA customers, except those handled by GSA. DESC informs me that
78 these timing changes will make the Request for Proposal (RFP) process much more manageable
79 and should permit a more deliberate and thorough evaluation of the government's supply
80 options. Unfortunately, it appears clear that these timing improvements cannot be put in place in
81 time to assist customers in making their decisions regarding power supply arrangements for the
82 2003 Period A beginning with the ending May meter reads. Even if the Commission were

83 interested, I do not see any way in which new rules could be established with an interim order
84 that would be subject to change in a final order. That is because the final order is scheduled to
85 be issued just five days before the end of the window during which customers would have to
86 decide which power supply option to pursue under the Company's new procedures. Thus,
87 DOE assumes that the existing MVI/PPO/CTC protocols would continue to apply to the 2003
88 Period A process.

89 Q. IS IT YOUR UNDERSTANDING THAT THE COMPANY'S RIDER CTC-MY
90 WOULD BE AVAILABLE FOR USE IN MAKING PERIOD A DECISIONS IN 2003?

91 A. Yes. My understanding is that the forward CTCs under Rider CTC-MY would be made
92 available on or about April 1st, along with the PPO prices and the charges under Rate CTC.

93 Q. EARLIER YOU STATED THAT THE COMPANY'S PROPOSED RIDER CTC-MY IS
94 A STEP IN THE RIGHT DIRECTION BUT DOES NOT GO FAR ENOUGH. IS
95 THAT CORRECT?

96 A. Yes.

97 Q. PLEASE PROVIDE THE BACKGROUND TO THIS ISSUE.

98 A. In Docket No. 02-0479, the Company requested that Rate 6L service for customers with
99 loads of 3 mW or more be declared "competitive" pursuant to Section 16-113 of the Electric
100 Service Customer Choice and Rate Relief Law of 1997 (the Restructuring Act). The
101 Commission decided to allow the Company's request to go into effect by operation of law.
102 Under the terms of the Company's new 6L Rate Schedule, a customer with a load of 3 mW or
103 more faces several critically important supply choices this spring. If that customer remains on
104 or moves back to Rate 6L, he will be able to continue on that service until June of 2006 at rates
105 that are frozen. If he chooses to take service under Rider PPO or from an ARES, then he will
106 be prohibited from returning to Rate 6L. The "Provider of Last Resort" service for that
107 customer will be the Company's Hourly Energy Pricing (HEP) option. If he chooses to leave
108 the fixed rate protection of Rate 6L to take advantage of lower costs of service under Rider

109 PPO, he also faces the risk of being forced off PPO service if market prices or delivery service
110 charges rise enough to reduce his CTC to zero, since a customer may only take PPO service if
111 it has a positive CTC. In that case he would be forced to take service from an ARES or under
112 HEP.

113 In Docket No. 02-0479, I and a number of other witnesses testifying on behalf of large 6L
114 customers, noted that many of these customers desire to manage price risk by obtaining an “all-
115 in” firm forward price. Having Rate 6L as a “backstop” service provided this hedge. If market
116 prices increased unexpectedly, a customer could always move back to bundled 6L service at
117 the end of its existing PPO or ARES contract. That is no longer an option given the
118 Commission’s Order in Docket No. 02-0479. In that same docket, I and several other
119 witnesses testified that, if the Company’s request were granted, we anticipated many
120 customers returning to Rate 6L effective with their May 2002 meter readings in order to gain
121 the price certainty offered by the 3-year grandfathering provision of Rate 6L.

122 Q. CAN’T CUSTOMERS SIMPLY OBTAIN 3-YEAR FIRM FIXED PRICE BIDS
123 FROM ALTERNATE SUPPLIERS?

124 A. It is possible to obtain such bids from an ARES for power and energy. However, it is unlikely
125 that an ARES will be willing to provide an “all-in” firm price bid for the three years ending with
126 the May 2006 meter read because it has no way of hedging the uncertain CTC charge.

127 Q. WILL THE COMPANY’S CTC-MY RIDER HELP IN THIS REGARD?

128 A. Yes. With availability of a 2-year fixed CTC, it is more likely that an ARES will offer an “all-
129 in” firm fixed price for this 2-year period. It is still unlikely, however, that an ARES will offer
130 this kind of contract for the full 3-years to June 2006 when the customer must leave Rate 6L,
131 because there remains the uncertainty of the CTC in the third-year.

132 Q. WILL THE AVAILABILITY OF A 2-YEAR FIXED CTC ELIMINATE THE
133 LIKELIHOOD THAT LARGE 6L CUSTOMERS WILL RETURN TO 6L SERVICE
134 RATHER THAN SEEK A COMPETITIVE POWER SUPPLY?

135 A. No. The failure to extend the CTC-MY to a third year will probably prevent many customers
136 from obtaining a fully hedged competitive supply until they must leave Rate 6L service.
137 Consequently, I believe a large number of these customers will return to Rate 6L at the end of
138 May 2003, since the failure to do so would constitute an irrevocable decision to rely on the
139 market in the future with all of the attendant uncertainties. What many customers are likely to
140 do is wait until the spring of 2004 to evaluate their options for the remainder of the transition
141 since, under the Company's proposal, they can get a locked-in CTC from June 2004 through
142 May 2006, and so should be able to obtain firm, "all-in" price bids from ARES for that two
143 years, which they can compare to the certainty of 6L rates.

144 The major risk that customers would run under this strategy is that the full 500 mW of
145 service under the CTC-MY Rider would be fully subscribed by the spring of 2004, and so they
146 would be unable to get CTC-MY service at that point. In my view, that is a risk that many
147 large 6L customers are likely to accept, since the worse case scenario is they would have to
148 forgo some savings by staying on Rate 6L for a year to gain price certainty.

149 Q. WHAT DO YOU PROPOSE THAT COMED DO?

150 A. If the Company genuinely wants the market to develop, then I believe it should take the extra
151 step and offer a multi-year locked-in CTC that would run from June 1, 2003 through May of
152 2006. That should facilitate the provision by ARES of "all-in" firm fixed-price bids that large
153 6L customers can compare this coming spring with 6L service through May 2006.

154 Q. WHY DO YOU BELIEVE THE COMPANY IS HESITANT TO OFFER A MULTI-
155 YEAR CTC BEYOND 2 YEARS?

156 A. My discussions with Company staff suggest that the Company is primarily concerned about the
157 relative lack of liquidity in the forward market for deliveries three years hence. My
158 understanding is that there are trades three years out and that the prices in those contracts
159 appear reasonable, but that there are relatively few transactions and most are for annual
160 contracts with few monthly trades to verify the annual data. The absence of monthly

161 observations is not really surprising since few buyers are likely to contract for delivery of power
162 in one month three years into the future.

163 Q. WHAT IS THE RELEVANCE OF THIS ILLIQUIDITY IN THE FORWARD
164 MARKET FOR THE THIRD YEAR?

165 A. Mr. Crumrine has testified that the uncertainty surrounding the MVI calculations beyond a year
166 “could expose both customers and ComEd to some CTC risk (i.e., CTC-MY payments could
167 be significantly more or less than annual CTC payments).” (Direct Testimony, page 17)
168 Presumably Mr. Crumrine believes these risks increase the further out one goes into the future.
169 Thus, the risks are greater when CTCs are fixed three years out as compared with two years
170 out. This is reasonable. However, the Commission needs to look more closely at the nature of
171 these risks.

172 First, locking-in a price for a future period always entails a risk that the locked-in price will
173 turn out to be higher than the current market price. Customers who prize certainty must accept
174 that risk. Since customers are not required to avail themselves of the CTC-MY option, they
175 would only do so voluntarily if they are more concerned about establishing price certainty in the
176 future than in being able to take advantage of potentially lower future CTCs. I think the
177 Company’s concern about customer risk exposure is misplaced.

178 Second, the Company will face some price risk, but it should be capable of fully hedging
179 that risk by entering into a forward contract to sell the energy released by a customer entering
180 into a CTC-MY agreement (or avoid buying energy for that customer) at prices reflective of the
181 future prices used to calculate the future MVI and CTC. Thus, if the market price turns out to
182 be lower and the CTC higher than forecast, the Company would remain whole, just as it would
183 if market price rose and the CTC fell.

184 Q. ARE THERE OTHER CONCERNS THAT MAY BE INVOLVED IN THE
185 COMPANY’S HESITANCE TO EXTEND THE CTC-MY TO A THIRD YEAR?

186 A. The Company may have a concern that, in any given year, customers may be paying
187 significantly different CTCs under Rate CTC and under Rider CTC-MY. That discrepancy is
188 potentially greater the further into the future the CTC-MY applies. If there were an attempt to
189 bring the CTC-MY charge down to the annual charge under Rate CTC after the Company has
190 hedged against these deviations, then the Company would not be made whole.

191 Q. WHAT COULD BE DONE TO AVOID THIS RISK FOR THE COMPANY?

192 A. It seems to me that the Rider should incorporate language that makes it clear that any customer
193 choosing to fix its CTC for future years has entered into a hard bargain, and that CTC will not
194 be changed even if there result large discrepancies between annual CTCs and charges under
195 CTC-MY. Similar language could also be incorporated into a CTC-MY agreement that each
196 subscribing customer would be required to execute, and the Commission could echo this
197 language in its Order in this proceeding. While parties are always free to raise whatever issues
198 they choose to in the future, such commitments today would make it very difficult for customers
199 served under the CTC-MY rider to complain about their future CTC costs under the Rider.

200 Q. SHOULD ANY ADJUSTMENTS BE ALLOWED TO CTCs SET FOR FUTURE
201 YEARS UNDER RIDER CTC-MY?

202 A. Yes. The only truly uncertain component in the CTC calculation is the future market value of
203 energy. The mitigation factor for future years is known. Distribution and transmission charges
204 for the future may not be known today, but the likelihood of reductions in these charges
205 probably approaches zero. Since the Company has primary control over when increases in
206 these charges will occur, and since there is little risk that changes in these charges will increase
207 the CTC, I believe the fixed CTCs for future years in the CTC-MY Rider should be adjusted
208 to account for actual distribution and transmission charges imposed at the time. The Company
209 appears to agree and this is captured in the language under "Calculation of Charges" in the
210 Company's proposed rider (Original Sheet No. 222). There it states that, "...the formula
211 provided in the Calculation of Charges section of Rate CTC shall be applied to the calculation

of the multi-year CTCs for such retail customer *except as provided in this Calculation of Charges section* (italics provided).”

Q. DR. SWAN, DO YOU HAVE CONCERNS REGARDING THE COMPANY’S PROPOSAL TO LIMIT RIDER CTC-MY TO THE FIRST 500 MW OF LOAD THAT SUBSCRIBE?

A. Yes. The length of the window during which a Large 6L customer will need to decide which power supply option to pursue for Period A is less than 2 months, and may be only somewhat greater than one month, depending on when in May his meter will be read. If the customer is to be able to obtain an all-in firm price bid from an ARES for two or three years, which he can compare to the certainty of Rate 6L, then he must know whether he will be able to secure service under the CTC-MY. This is further complicated by the noticing provisions under PPO that require 30 days to cancel existing PPO service. Most customers will probably not be able to make final decisions until toward the end of May. This certainly includes the FEA Large 6L customers, since DESC must have its RFP “on the street” for a minimum of 40 days. My concern is that many customers will be requesting CTC-MY service at the same time toward the end of the month. If decisions are made contingent upon receiving CTC-MY service, and then that service is denied at the last minute because the 500 mW limit has been reached, there is likely to be inadequate time for the customer to make other arrangements.

Moreover, I do not see the need for the limit. Mr. Crumrine indicates that the primary reason for the constraint is to limit exposure to price risk for both customers and ComEd. As I explained earlier, these customers need not be protected since they would be making voluntary determinations that whatever price risks they take on are worth obtaining CTC certainty. Further, ComEd is capable of fully hedging whatever price risk is associated with the provision of CTC-MY service. For all of these reasons, I would urge the Commission to encourage ComEd not to limit the availability of Rider CTC-MY.

237 Q. DO YOU HAVE ANY CONCLUDING REMARKS REGARDING THE CTC-MY
238 PROPOSAL?

239 A. Yes. It is my understanding that the Company is willing to consider a third year fixed CTC as
240 part of the Rider CTC-MY, even on the basis of relatively thin data on forward trades three
241 years out. However, it is concerned with how parties might use any resulting discrepancies
242 between charges paid under Rider CTC-MY and the annual Rate CTC. I believe that having
243 the price certainty that a 3-year CTC could provide of such importance that I would urge the
244 Commission to direct the Company and all interested parties to meet in order to seek
245 agreement on how a 3-year forward CTC can be provided, and what protections the Company
246 would need if it were to extend the CTC-MY to a third year. To allow this to be part of the
247 decision process for 2003 Period A decisions, if the Commission sees fit to issue an order
248 adopting the Company's proposal, such discussions should be held as early as possible –
249 certainly well before the Commission is scheduled to issue a final order in this proceeding.
250 DOE would be a willing participant in any such discussion.

251 Q. DOES THIS COMPLETE YOUR TESTIMONY?

252 A. Yes.

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DALE E. SWAN

Dr. Swan is a senior economist and principal at Exeter Associates, Inc. His areas of expertise include energy supply and demand analysis, electric industry restructuring, utility cost allocation and rate structure design, utility contract negotiation, antitrust policy, and public utility regulation.

Dr. Swan has given expert testimony in utility rate cases before the Federal Energy Regulatory Commission and before numerous state regulatory commissions. He has testified on marginal and embedded costing, rate structure design, long-term demand forecasting, short-term sales forecasts, the treatment of off-system sales, electric industry restructuring, and antitrust considerations. He has directed major projects for the U.S. Department of Energy, the U.S. Air Force, and the Rhode Island Public Utilities Commission on such issues as alternative power supply options and innovative rate structure experiments and implementation, and he has prepared and presented seminars and workshops on such issues as marginal costing, rate design, and interruptible rates for, among others, the National Regulatory Research Institute, the U.S. Department of Energy, and for state commission staffs in Maryland, Minnesota, and New Hampshire.

Dr. Swan has assisted federal agencies in the negotiation of electric power supply contracts and in the financial and locational assessment of transmission and generation projects; he has also prepared reports to several federal and state agencies on costing methods, rate design, the demand for electric power, PURPA requirements, bulk power supply planning, stranded cost recovery, standby rates, value-of-service pricing, the use of special contracts, and other issues. He has also acted as an Advisor to the Maine Public Utilities Commission in the restructuring proceedings for the three investor-owned Maine electric companies.

Education:

B.S. - (Business Administration) - Ithaca College, 1962.

M.A. Program in Economics - Tufts University, 1962-63.

Ph.D. - (Economics) - University of North Carolina at Chapel Hill, 1972.

Previous Employment:

1976-1980	-	Senior Economist, J.W. Wilson & Associates, Inc.
1974-1976	-	Associate Professor of Economics, Jacksonville State University
1974	-	Economist, Office of Energy Systems, Federal Energy Administration

1973	-	Staff Economist, Economics Department, Arabian-American Oil Company
1968-1973	-	Assistant and Associate Professor of Economics, Hampden-Sydney College
1969-1973	-	Visiting Assistant Professor of Economics, Randolph-Macon Womens College
1967-1968	-	Assistant Professor of Economics, Southern Methodist University
1966-1967	-	Visiting Assistant Professor of Economics, North Carolina Central University
1963-1964	-	Market Research Analyst, The Carter's Ink Company

Previous Professional Work:

At J.W. Wilson & Associates, Inc., Dr. Swan had primary responsibility for the development and direction of several of the firm's largest projects relating to the electric utility industry and costing and rate design issues in particular. Dr. Swan also had major responsibilities in the areas of cogeneration, antitrust, PURPA requirements, and technical assistance to state regulatory authorities under DOE grant programs.

At the Federal Energy Administration, Dr. Swan participated in the development of a National Energy Accounting System, similar to and compatible with the National Income and Product Accounts and the U.S. Input/Output Accounts. During his tenure at Jacksonville State University, Dr. Swan continued with this work as a consultant to the FEA.

While with ARAMCO, Dr. Swan prepared financial analyses of capital investment alternatives, developed cost trend estimates for price negotiations, and initiated the preparation of revised price trend factors to be used for budgeting purposes.

At Carter's Ink Company, Dr. Swan was responsible for conducting new product and new market research for the Director of Marketing, including consumer attitudinal studies on new product and packaging designs.

Dr. Swan has taught both graduate and undergraduate courses during his academic career. Among the courses he has taught are Microeconomic Theory, Industrial Organization, Economic History, International Trade, Economic Development, and Principles of Economics.

Selected Publications, Papers, and Reports:

“A Comparative Evaluation of Two Proposals to Meet the Long-Term Steam Requirements of the Savannah River Site.” (Exeter Associates, Inc., for the U.S. Department of Energy, Federal Energy Management Program, November 2001.)

“Electric Power Supply Options to Meet the Cold Standby and Possible Restart Requirements of the Portsmouth Gaseous Diffusion Plant.” (Exeter Associates, Inc. for the U.S. Department of Energy, Federal Energy Management Program, October 2001.)

“Strategic Options in Planning for the Long-Term Power Requirements of the DOE/OAK Laboratories.” (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, September 1998.)

“Utility Options Study: Rocky Flats Environmental Technology Site.” (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Fixed Asset Management, March 1997.)

“Competitive Acquisition of Power by Federal Agencies: Current Possibilities and Future Prospects.” (Presented before the Competitive Power Congress, Philadelphia, Pennsylvania, July 21, 1995.)

“Standby Rate Rulemaking: A Discussion of Issues and Proposed Positions.” (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 10, 1995.)

“Stranded Cost Rulemaking: A Discussion of Issues and Proposed Positions.” (Exeter Associates, Inc. for the Maine Public Utilities Commission, January 3, 1995.)

“Superconducting Super Collider Permanent Power Supply: A Preliminary Consideration of Supply Alternatives.” (Exeter Associates, Inc., revised draft report prepared for the U.S. Department of Energy, Office of Organization, Resources and Facilities Management, March 1992.)

“The Potential Savings Associated with Exporting EBR-II Energy from the Idaho National Engineering Laboratory to Another Federal Facility.” (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, March 1991.)

“Planning and Preparing a Utilities Options Study,” in Utilities Planning and Management for Department of Energy Facilities. (U.S. Department of Energy, February 1990.)

“An Evaluation of the Financial Benefits to the United States Government from Using \$175 Million of the TRNLC Fund to Purchase Generating Capacity to Reduce Power Costs of the

Superconducting Super Collider.” (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, January 1990.)

"Power Supply Arrangements at Brookhaven National Laboratory." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, October 1989.)

"Electric Power Supply Options for the Continuous Electron Beam Accelerator Facility." (Exeter Associates, Inc. for the U.S. Department of Energy, Office of Project and Facilities Management, July 1989.)

"The Potential Future Value of Byproduct Steam from a New Production Reactor Based on Four Alternative Technologies and Three Alternative Sites," with Steven Estomin and Richard Galligan. (Exeter Associates, Inc. for the U.S. Department of Energy, August 1988.)

"An Analysis of the Optimal Allocation of Available Western Area Power Administrative Preference Power Among Three Northern California Laboratories," with Charles E. Johnson. (Exeter Associates Inc. for DOE San Francisco Operations Office, March 1986.)

"Report on the Role of Special Contracts in Electric and Gas Utility Ratemaking." (Exeter Associates, Inc. for the U.S. Postal Service, February 1984.)

"The Electric Utility Industry," in Study of Pricing Precedents in the Public Utility Industry. (Exeter Associates, Inc., for the U.S. Postal Service, February 1984.)

"State Regulatory Attitudes Toward Fuel Expense Issues," with Matthew I. Kahal, Report to the Electric Power Research Institute, June 1983.

"A Summary and Analysis of Federal Legislation Affecting Electric and Gas Utility Diversification." (Exeter Associates, Inc. for Argonne National Laboratory, August 1981.)

"Average Embedded Cost Studies as the Basis for Rate Designs Consistent with the Goals of the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 6, 1981.

"Analysis of the Major Comments Made on the ERA Proposed Voluntary Guideline for the Cost-of-Service Standard Under the Public Utility Regulatory Policies Act of 1978," prepared for ORI, Inc. and the DOE Office of Utility Systems, February 1981.

"The Rhode Island - DOE Electric Utilities Demonstration Project." Final Report - November 1980, and three Interim Reports in July 1978, November 1979, and July 1980. (J.W. Wilson & Associates, Inc. for the Rhode Island Division of Public Utilities and Carriers.)

"An Evaluation of Power Supply Planning by the Six Investor-Owned Electric Utilities in South Dakota," with Ralph E. Miller. (J.W. Wilson & Associates, Inc. for the South Dakota Public Utilities Commission, 1977.)

The Structure and Profitability of the Antebellum Rice Industry: 1859. (New York: Arno Press, 1975.)

"The Structure and Profitability of the Antebellum Rice Industry: 1859." Journal of Economic History, (December 1972.)

"The Productivity and Profitability of Antebellum Slave Labor: A Micro Approach," with James D. Foust. Agricultural History, (January 1970). Later published in William N. Parker (ed.), The Structure of the Cotton Economy of the Antebellum South. (New York: Agriculture History Society, 1970.)

Participation in Conferences, Seminars and Workshops:

Competitive Power Congress, 1995.

Department of Energy Utility Conferences, 1985, 1986, 1990, 1992, 1995, 1996, 1997.

DOD/DOE Combined Utility Planning Conference, March 1987.

American Historical Association Meetings, 1981.

National Regulatory Research Institute Workshop on Time-of-Use Rates, September 1979.

National Regulatory Research Institute State Needs Assessment Conference, August 1979.

Southern Economic Association Meetings, 1969, 1972, 1975.

Economic History Association Meetings, 1972.

Expert Testimony

Presented by Dale E. Swan

1. Before the Public Utilities Commission of the State of Ohio, Case No. 78-676-EL-AIR, on marginal costs and electric rate structure design.
2. Before the Public Utilities Commission of the State of South Dakota, Docket No. 3362, on marginal costs and electric rate structure design.
3. Before the Public Utilities Commission of the State of South Dakota, Docket Nos. F-3240 and F-3241, on electric rate structure design.
4. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1311, on the design of a proposed inverted rate structure experiment.
5. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1262, on the operation and the results of a time-of-day rate experiment.
6. Before the Public Utilities Commission of the State of South Dakota, Docket No. F-3116, on test year sales forecasts.
7. Before the Public Utilities Commission of the State of Montana, Docket No. 6441, on test year sales forecasts.
8. Before the Public Service Commission of the State of Maryland, Case No. 6807, on long-term demand forecasting methodology.
9. Before the Public Service Commission of the State of New York, Docket No. 27136, on test year sales forecasts and economic impact.
10. Before the Federal Energy Regulatory Commission, Docket No. ER77-530, on retail competition in the Ohio electric power market.
11. Before the Public Service Commission of the State of Maryland, Case No. 7441 (Phase III), on electric rate structure design and PURPA ratemaking standards.
12. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1591, on class revenue requirements and electric rate structure design.

13. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1606, on PURPA Section 111 standards, class cost-of-service, and rate structure design.
14. Before the Public Utilities Commission of the State of Rhode Island, Docket No. 1605, on class revenue requirements and electric rate structure design.
15. Before the Public Utilities Commission of the State of Idaho, Case No. U-1006-185, on class revenue requirements and rate design.
16. Before the Illinois Commerce Commission, Docket No. 82-0026, on marginal-cost-based class revenue responsibilities and rate design.
17. Before the Public Utilities Commission of the State of Idaho, Case No. U-1009-120, on contractual arrangements, embedded-cost-based class revenue requirements, and rate design.
18. Before the Public Utilities Commission of the State of Maryland, Case No. 7695, on proper electric class cost-of-service methodologies.
19. Before the Public Service Commission of Nevada, Docket No. 83-707, on marginal-cost-based class revenue responsibilities and rate design.
20. Before the Illinois Commerce Commission, Docket No. 83-0537, on marginal-cost-based class revenue responsibilities, rate design, and rate schedule qualification standards.
21. Before the Public Utilities Commission of the State of Idaho, Case No. U-1009-137, on jurisdictional separations, embedded class cost-of-service studies, interruptible service credits, and class revenue requirements.
22. Before the South Carolina Public Service Commission, Docket No. 84-122-E, on embedded class cost-of-service methodologies, class revenue requirements, and rate design.
23. Before the Public Utilities Commission of the State of Idaho, Case No. U-1500-157 (May 1985), on the public interest aspects of declaring one utility as the sole supplier of the Idaho National Engineering Laboratory.
24. Before the Illinois Commerce Commission, Docket Nos. 83-0537 (Step 2) and 84-0555 (Consolidated), June 1985, on marginal-cost-based class revenue responsibilities and rate design.
25. Before the Public Utilities Commission of the State of Idaho. Case No. U-1006-265A (May 1987), on embedded class cost-of-service studies, class revenue requirements, and rate design.

26. Before the Public Utilities Commission of the State of Maine, Docket No. 86-242 (August 1987), on by-pass and incentive rate discounts for large industrial customers.
27. Before the Illinois Commerce Commission, Docket No. 87-0427, (February and April 1988), on marginal-cost-based class revenues, Ramsey pricing considerations, and industrial rate design.
28. Before the Illinois Commerce Commission, Docket No. 87-0695, (April 1988), on marginal-cost-based class revenues, Ramsey pricing issues, and industrial rate design.
29. Before the Indiana Utility Regulatory Commission, Cause No. 37414-S2 (October 1989), on ratemaking treatment of off-system sales, embedded cost-of-service study, and rate design.
30. Before the Public Utilities Commission of the State of Maine, Docket 89-68 (January 1990), on measurement and use of marginal costs for determining class revenues.
31. Before the Federal Energy Regulatory Commission, Docket No. EC90-10-000, *et. al.* (May 1990), with Matthew I. Kahal, on the potential effects of the Northeast Utilities acquisition of Public Service New Hampshire on market concentration and competition in the New England bulk power market.
32. Before the Illinois Commerce Commission, Docket No. 90-0169 (August and October 1990), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.
33. Before the Public Service Commission of Nevada, Docket Nos. 91-5032 and 91-5055 (September 1991), on the estimation of marginal costs, class revenue responsibilities and rate design for large power users.
34. Before the Public Service Commission of Nevada, Docket No. 92-1067 (May 1992), on the estimation of marginal costs, the cost of providing interruptible power, class revenue responsibilities, and rate design for large power users.
35. Before the Public Utilities Commission of the State of Maine, Docket No. 92-095 (February 1993), Affidavit regarding the efficacy of rate discounts in attracting new business.
36. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (June 1993), on revamping of the rate structure to meet competition for sales.
37. Before the Public Utilities Commission of the State of Maine, Docket No. 92-345 (August 1993), with Marvin H. Kahn, on price cap mechanisms as an alternative form of regulation.

38. Before the Public Service Commission of Nevada, Docket No. 92-9055 (October 1993), on franchise rights to serve a large DOE customer.
39. Before the Illinois Commerce Commission, Docket No. 94-0065 (June 1994), on the estimation of marginal costs, class revenue responsibilities, and industrial rate design.
40. Before the Public Service Commission of Nevada, Docket No. 93-11045 (June 1994) on the estimation of marginal costs, environmental externality adders, competition for loads, and class revenue responsibilities.
41. Before the Idaho Public Utilities Commission, Case No. IPC-E-94-5 (November 1994), on embedded class cost allocation and class revenue responsibilities.
42. Before the Public Utilities Commission of the State of Maine, Docket No. 92-315 (II) (March 1995), on the estimation of marginal distribution demand and customer costs.
43. Before the Public Utilities Commission of the State of Maine, Docket No. 95-052 (RD) (October 1995 and January 1996), with Daphne Pscharopoulos, on the estimation of marginal costs as the basis for class revenues and rate design.
44. Before the Public Service Commission of Nevada, Docket No. 96-7020 (November 1996), on the estimation of marginal costs, class revenue responsibilities, and the reasonableness of fixed, up-front facilities charges.
45. Before the Public Service Commission of Montana, Docket No. 97.7.90 (November 1997 and March 1998), on aspects of Montana Power Company's proposed restructuring plan.
46. Before the Illinois Commerce Commission, Docket No. 99-0117 (April 1999), on the design of distribution delivery rates for Commonwealth Edison Company.
47. Before the Public Utilities Commission of Nevada, Docket Nos. 99-4005 and 99-4006, (November 1999), on the design of an electric distribution service tariff for Nevada Power Company.
48. Before the Public Utilities Commission of Nevada, Docket No. 99-7035 (January and February 2000), on Nevada Power proposed revision to its base rates and deferred energy adjustment rates, including the recovery and allocation of deferred capacity costs and the appropriate calculation of annualized fuel and purchased power costs.
49. Before the Illinois Commerce Commission, Docket No. 01-0423 (August, October 2001), on the proper design of distribution delivery rates for Commonwealth Edison Company.

50. Before the Public Utilities Commission of the State of Maine, Docket No. 2001-239 (November 2001), on appropriate procedures governing the provision of rate discounts to retain or attract customers.
51. Before the Public Utilities Commission of Nevada, Docket Nos. 01-10001, 01-10002 and 01-11029 (February 2002), on Nevada Power Company's proposed class cost allocations and revisions to its base rates.
52. Before the Illinois Commerce Commission, Docket No. 02-0479 (August 2002), on the appropriateness of the Company's petition to have bundled Rate 6L service to customers with loads of 3 MW or more declared a competitive service, thereby eliminating Rate 6L as a service of last resort for these customers.